Energy Choice Matters

July 9, 2008

REPs Oppose Interim Relief for CenterPoint AMS Surcharge

CenterPoint Energy should not be granted interim relief for a surcharge related to its advanced metering system (AMS) deployment, REPs told the PUCT (35639).

The Alliance for Retail Markets noted that while CenterPoint has requested to implement the surcharge in the interim, which will take the form of a nonbypassable charge on REPs who will need to recover such costs from their customers, such relief will not accelerate AMS deployment before the fall of 2009 (Matters, 5/6/08).

CenterPoint's argument that it needs the cash flow from accelerated imposition of part of the AMS surcharge lacks meaningful detail, ARM added.

Any purported cash flow benefits are outweighed by the lengthening of the period between the date when REPs (and ultimately their customers) begin to pay the infrastructure surcharges, and the date when smart meters are first deployed under AMS, ARM added. If interim relief is granted, about a year will elapse from the time customers start paying for the meters and the first deployment. Absent interim relief, that period would be about nine months.

TXU added that only about 1/8th of the customers in CenterPoint's footprint are even scheduled to get an advanced meter under CenterPoint's current AMS deployment plan, further compounding the inequity of interim relief.

Interim relief won't save customers an appreciable amount of money, ARM observed. The levels of the surcharges are only negligibly higher if interim relief is not granted. For example, if interim relief is denied, the proposed infrastructure surcharge for residential customers would be a mere

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Non-CAISO LSEs See Losing Proposition in Single Hub Pricing for Imports

Load serving entities outside of the California ISO control area attacked CAISO's Integrated Balancing Authority Areas (IBAA) filing which would create a single hub price for scheduled imports into the CAISO from several neighboring Balancing Authority Areas (ER08-1113).

The ISO has proposed the proxy hub as a means to price imports and exports in a manner consistent with LMP under its Market Redesign and Technology Upgrade (MRTU) and to ensure feasible schedules. The approach is also necessitated, CAISO says, because it lacks information about the external resources which support interchange transactions. Essentially the problems relate to loop flows and seams.

But the City of Redding, California, in sentiments shared by many external LSEs, sees the single hub pricing plan as forcing, "unjust, intentionally low prices on imports to the CAISO, while selecting a high cost LMP for all exports." That's because the ISO selected one of the lowest-cost hubs on the system, the Captain Jack substation, as the proxy import hub. By using that hub, located at the CAISO's connection to the Pacific Northwest and the region's cheap hydropower, the CAISO would, by default, price all imports at the hub's cheap price.

While entities may opt out of using the default single hub price, they must share confidential, commercially sensitive information to do so. The information allows CAISO to model external LSEs' flows better. But LSEs are worried about disclosing that sensitive information, and WestConnect

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NCPA Presses FERC on MRTU Testing

"A second California meltdown would be the death knell for [FERC's] perceptions of the markets, and neither the Commission nor CAISO management should permit themselves to be railroaded into that position because of understandable frustration," with the delay of the original CAISO Market Design 2002, the Northern California Power Agency told FERC, again raising concerns with the schedule and testing process for the Market Redesign and Technology Upgrade (ER06-615).

NCPA believes that its earlier concerns have been ignored (Matters, 6/18/08, 6/3/08), and that a fall MRTU start, "will lead to failure, potentially causing NCPA and other smaller entities great harm, and causing potential damage to the California and Western markets in the process."

Essentially, NCPA reiterated that the ISO is pushing ahead with a fall Go-Live date despite giving market participants inadequate time to test their systems against a fully functioning CAISO system.

NCPA reported several incidents which it believes show CAISO's dismissal of stakeholder concerns about testing.

At a June 24 market participant meeting, NCPA reported that CAISO management stated that, after consultations with market participants, CAISO management had decided that the three-month participant testing period was going to start July 1.

According to NCPA, when the project manager was asked by NCPA when these discussions took place, the project manager responded that the CAISO had consulted individually with selected market participants. NCPA then asked for a show of hands from the assembled market participants as to who had been contacted for these discussions. No hands were raised, NCPA said. Later discussions with a variety of market participants who had checked in with their offices yielded no evidence of any such discussions, NCPA claimed. While NCPA understands that the referenced discussions may have taken place at a much higher level of management than those represented in the room, a trend toward such discussions without consultation with involved staff would be a very disturbing development, NCPA cautioned.

NCPA criticized the ISO's declaration of "substantial readiness" by July 1 as even more questionable since a significant software function, the Forbidden Zone release, was not even activated until July 5.

NCPA also noted that with July being the first full month of allegedly accurate data, the data necessary for settlements will not be available until mid-August. As a result, market participants will not know until mid August at the earliest, whether their systems are actually working or not. Because Mid-August assumes that market participants can access and analyze all of the data immediately, which is a highly unlikely occurrence, such an assessment is more likely to be completed around the beginning of September, NCPA argued.

According to NCPA, CAISO's initial response to this concern was to assert that settlement data has been available for the last three months.

"Virtually every Market Participant in the room challenged that CAISO assertion, with the majority responding that the prior three months data were intermittent, provided from systems that had not been tested under significant upgrades installed during the month of March, and exhibited significant errors and problems regarding quality of solution," NCPA claimed.

Briefly:

Fitch Sees Little Credit Impact to Texas Market Participants from Price Spikes

Fitch Ratings does not foresee any adverse credit effects as a result of recent price spikes for Texas generators, electric transmission and distribution companies, utility tariff bonds and REPs, it reported in Perspectives on ERCOT Power Price Spikes. If ERCOT actions to reduce extremely high MCPEs seen in May are not successful, small REPs that purchase much of their energy needs on the spot market due to lack of sufficient hedging or liquidity support are the most at risk for default, Fitch affirmed. "Larger REPs that have effectively managed their liquidity position to hedge power supply are currently not at material risk from spiking spot power prices," Fitch concluded. Although TDSPs have counterparty risk to REPs that collect customer revenues for the utilities, Fitch noted exposure is limited by the TDSPs' ability to recover uncollected receivables in rate filings. Fitch believes the credit risk to generators is neutral due to their significant hedged position.

PUCT Wants Comments on Demand Ratchets

The PUCT Staff has asked for public comments on the use of demand ratchets (35855). Staff asked whether the current method of demand ratcheting is appropriate, and how to set appropriate percentage levels at which to set ratchets. Which customers should be subject to demand ratcheting and what should the criteria be, the Staff asked. The Staff questioned whether any specific customers should be exempt from ratcheting, and if so, from what customer classes should any revenue shortfall caused by the exemption be recovered. Comments are due August 8.

ERCOT Released RPRS Award Info to Wrong QSEs

ERCOT had been "sporadically" sending Client Data Reports containing QSE-specific Replacement Reserve Service (RPRS) bidding award information for four QSEs to the wrong QSEs during 2006, 2007, and 2008 due to a program coding error, in violation of P.U.C. SUBST. R. 25.505(f)(3)(A)(i) and ERCOT protocols, it reported to the PUCT (27706). The QSEs whose data was improperly disclosed were Calpine, Austin Energy, City of Garland, and NRG. Those wrongly receiving the data were Liberty Power, Pilot Power Group, APX, and Austin Energy (which received another QSE's data rather than its own). The error occurred 180 times over the three-year period before ERCOT discovered and corrected the problem.

Maine PUC Opens Docket on Wind, Solar Rebates

The Maine PUC opened an inquiry (2008-267) to adopt rules to implement Maine's wind energy rebate program, revise current rules for Maine's solar rebate program and implement a small wind power generator pilot project, as required by recent legislation. L.D. 349 provides for a one-time General Fund Appropriation of $40,000 for fiscal year ending 2008-2009 for the Commission to authorize and fund a small wind power generator pilot project, defined as "an electricity generating installation certified by the Commission at any one site that includes a turbine of not more than 10 kilowatts that is powered entirely by wind energy and intended to serve the electricity needs of a household or small business." L.D. 2283 creates a wind rebate program, requires the PUC to allocate funds between the solar and wind energy rebate programs and requires the Commission to determine the allotment of funds between solar PV rebates, solar thermal rebates and qualified wind energy system rebates, with a minimum of 20% of the fund provided to each of the three. The PUC asks how to allocate funds and whether it should establish different incentive levels for various solar and wind rebate projects. Comments are due July 28.

Calif. PUC Draft Would Open Rulemaking for Efficiency Strategy Plan

A draft decision by the California PUC would open a rulemaking to develop a California Strategic Plan for Energy Efficiency through the year 2020 and beyond. The rulemaking is to incorporate the efforts of the IOUs, which jointly filed Application 08-06-004 to propose a California Energy Efficiency Strategic Plan (CEESP). The draft opts for a rulemaking rather than approving, rejecting or modifying the utilities' strategic efficiency plan so it can include other statewide efforts not localized to the IOUs. The rulemaking would be consolidated with A. 08-06-004 and would allow for development of a record and consideration of ideas above and beyond the detailed strategies and implementation plans discussed in the utilities' application. Among the questions asked by the draft is how should the Commission Strategic Plan coordinate energy efficiency plans with demand response plans and solar programs?

EnerNOC Reports $500 Million in Contracted Sales

EnerNOC reported yesterday that is has surpassed $500 million in contracted revenues. EnerNOC expects roughly 90% of the contracted revenue to be earned by May 31, 2012 and the remainder to be earned through 2018. Revenues include fees for demand response as well as energy management and energy procurement. EnerNOC has over 1,500 MW of demand response capacity under management and more than 3,000 customer sites enrolled in its demand response network.

Vectren Blames Marketing Unit for Expected Lower Earnings

Based primarily on lower earnings expectations from Vectren Corp.'s gas marketing business, Vectren lowered annual earnings expectations for its nonutility group \$0.15 to \$0.23 per share from \$0.31 to \$0.42 per share. As a result, second quarter 2008 earnings for the entire conglomerate are expected to be below analyst estimates. Vectren blamed continued low volatility in the wholesale gas markets, which has significantly impacted ProLiance Energy's ability to optimize storage and transportation opportunities, for the expected lower results.

CenterPoint AMS ... *from 1*

\$0.000087/kWh higher, or \$1.57 per year for a residential customer using 1,500/kWh per month. ARM argued that such scant savings do not warrant the burden of interim relief.

The Texas Energy Association for Marketers noted that CenterPoint is seeking relief via an interim surcharge for a service that may never be implemented at the sole discretion of CenterPoint, since its board of directors may ultimately decide to not pursue AMS deployment. Thus CenterPoint has failed to meet its burden for showing a need for interim relief.

CenterPoint has also requested interim approval of seven new discretionary charges applicable to REPs serving customers with advanced meters. The charges relate to move-ins/move-outs, disconnection/reconnection of service in the context of non-payment, and meter reads, including out-of-cycle meter reads. The fees are lower than the charges currently assessed to customers served by the current legacy meters.

While ARM has not yet fully evaluated the levels of the proposed discretionary charges and reserved the right to do so in presenting its case, ARM saw no reason that customers receiving smart meters (such as those through the accelerated AMIN program) should not receive the full benefit of those meters' advanced functionalities relating to electric utility service, and supported interim approval of the discretionary charges.

CAISO IBAA ... *from 1*

claimed that the single hub pricing plan is merely a "biased formulation intended to pressure [LSEs] into executing confidential data exchange agreements in order to obtain reasonable pricing arrangements."

Powerex noted that Eastern RTOs have moved away from having two default pricing hubs unique to exports or imports to avoid having market participants submit import schedules at higher priced locations and export schedules at lower priced locations. It suggested that the ISO use a single hub for both imports and exports.

Pacific Gas and Electric and Southern California Edison, however, generally supported the CAISO proposal, with PG&E arguing that the Captain Jack substation is a reasonable approximation of the marginal resource likely to support imports.

Northern California Power Agency cautioned that the single hub proposal could actually prevent cheaper power from being imported to CAISO. NCPA suspects that many entities will choose to avoid selling low at the Captain Jack hub price by minimizing their interchange transactions, probably by increasing their use of contract exchanges with other entities, such as by using resources within the CAISO BA to serve CAISO BA load and resources outside the BA to serve load external to the CAISO BA.

Given that the purpose for building the California-Oregon Transmission Project in the first place was to access cheaper Northwest energy for California, it is ironic that the CAISO's IBAA proposal will likely result in higher cost power serving loads in the CAISO BA and lower cost energy staying outside of the CAISO BA, with a commensurate effect on CAISO prices, NCPA observed. "However, that is simply a result of a proposal that has not been thoroughly assessed," NCPA argued.

Powerex noted that the CAISO proposal is designed to benefit CAISO ratepayers by having imports priced low and exports priced higher, while external LSEs of course want the reverse to minimize their customers' costs. "[I]f each party continues to adhere rigidly to its position, this will only work to the detriment of all market participants," Powerex cautioned. It urged FERC to provide guidance on seams to assist the parties in resolving the problems before the IBAA mechanism becomes effective.